



Energy Technologies Area

Lawrence Berkeley National Laboratory

Introduction to Wholesale and Retail Demand Response with a Focus on Measurement and Verification

April 13, 2017

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**National Association of Regulatory Utility Commissioners
National Association of State Energy Officials**

Introduction

- ◆ LBNL is supported by the U.S. Department of Energy to conduct non-classified research, operated by the University of California
- ◆ Provides technical assistance to states—primarily state energy offices and utility regulatory commissions

The presentation was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability-National Electricity Delivery Division under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Technical Assistance

- ◆ LBNL's provides technical assistance to state utility regulatory commissions, state energy offices, tribes and regional entities in these areas:
 - ❑ Energy efficiency (e.g., EM&V, utility programs, behavior-based approaches, cost-effectiveness, program rules, planning, cost recovery, financing)
 - ❑ Renewable energy resources
 - ❑ Smart grid and grid modernization
 - ❑ Utility regulation and business models (e.g., financial impacts)
 - ❑ Transmission and reliability
 - ❑ Resource planning
 - ❑ Fossil fuel generation
- ◆ Assistance is independent and unbiased
- ◆ LBNL Tech Assistance website: <https://emp.lbl.gov/projects/technical-assistance-states>
- ◆ US DOE Tech Assistance gateway: <http://energy.gov/ta/state-local-and-tribal-technical-assistance-gateway>

Webinar Series

- ◆ Webinars designed to support EM&V activities for documenting energy savings and other impacts of energy efficiency programs
- ◆ Funded by U.S. DOE in coordination with EPA, NARUC and NASEO
- ◆ Audience:
 - Utility commissions, state energy offices, state environment departments, and non-profits involved in operating EE portfolios
 - Particular value for state officials starting or expanding their EM&V
 - Evaluation consultants, utilities, consumer organizations and other stakeholders also are welcome to participate
- ◆ For more information (upcoming and recorded webinars, EM&V resources) see:
 - <https://emp.lbl.gov/emv-webinar-series>
 - General Contact: EMVwebinars@lbl.gov

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Next Webinar

- ◆ More webinars coming for 2017 and beyond...



- ◆ Possible May webinar:

Advances in Efficiency EM&V - DOE's Uniform Methods Project and (E)M&V 2.0

Today's Webinar – Demand Response and M&V

◆ What is Demand Response (DR)?

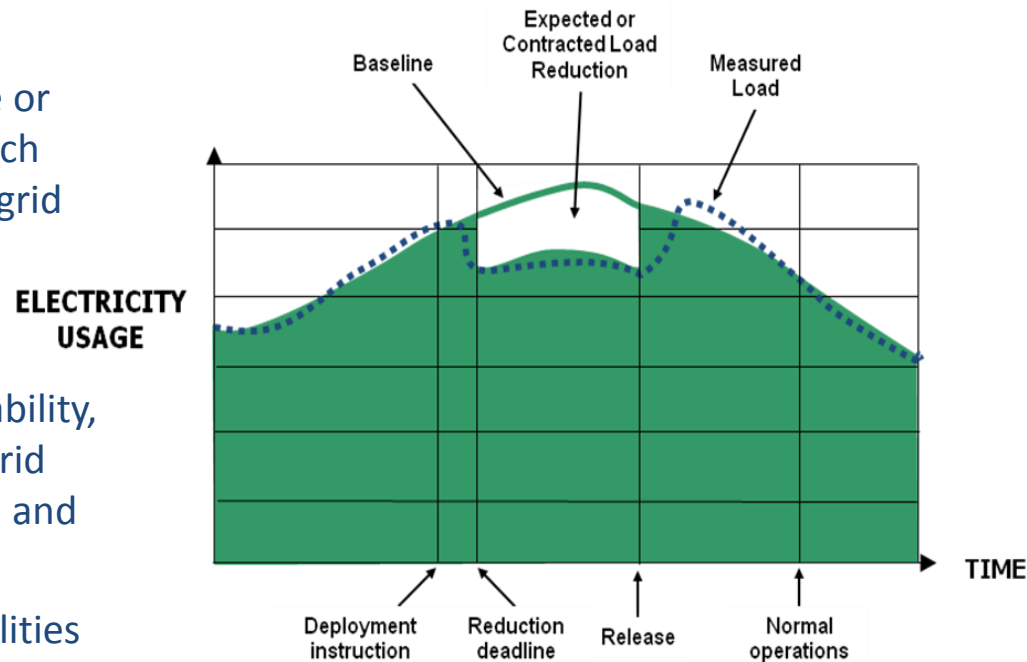
- ❑ One of multiple demand side strategies along with efficiency, distributed generation, distributed storage
- ❑ DR allows electricity consumers to increase or decrease demand at certain times when such action would be helpful support the utility grid network

◆ Why DR?

- ❑ DR supports capacity needs, improved reliability, reduced wholesale and retail costs, and a grid with higher levels of distributed generation and variable-output renewable resources
- ❑ Grid modernization is expanding DR capabilities and potential benefits.

◆ Why Measurement and Verification (M&V)?

- ❑ Assessing changes in electricity consumption resulting from DR pricing and incentive programs is a critical element in assessing their value and improving performance



Source: NAESB

Today's Speakers

◆ Demand Response Basics

- Jennie Potter, Senior Scientific Engineering Associate, Berkeley Lab
- David Kathan, Senior Economist, Office of Energy Policy and Innovation, Federal Energy Regulatory Commission

◆ M&V for Demand Response

- Mark S. Martinez, Sr. Portfolio Manager, Southern California Edison
- Peter Langbein, Manager, Demand Response Operations, PJM



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Retail Demand Response Programs

*Introduction to Wholesale and Retail Demand Response
with a Focus on Measurement and Verification*

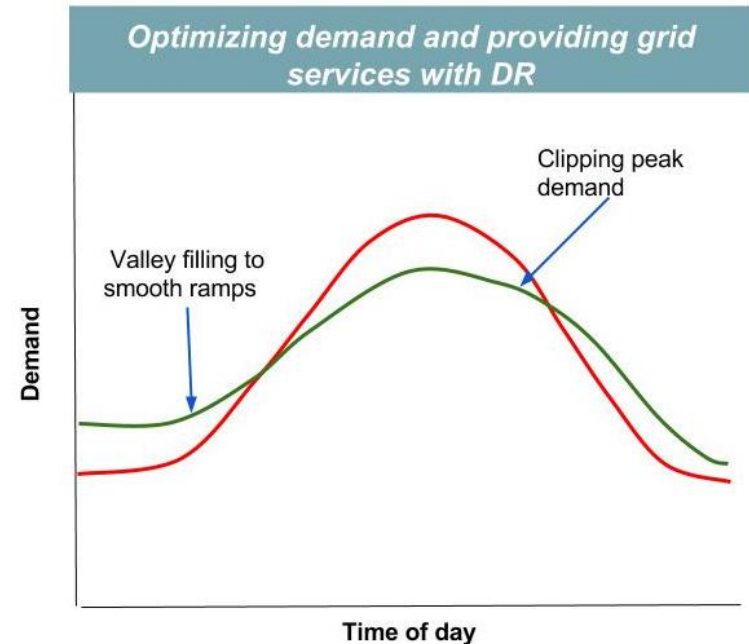
EM&V Webinar Series

Jennifer Potter, Senior Scientific Engineering Associate
Energy Technologies Area, LBNL

4/13/2017

Defining Demand Response

A mechanism through which an end-use's load profile is changed with price signals or with automated control, (by the user, a third party, or a utility) in response to system needs, often in return for economic compensation (e.g., payments or a different rate structure).



Retail Demand Response Service Providers



Types of DR Opportunities

Time-Based Retail Rates	Incentive-Based Programs	
DR signal: Price Level	DR signal: System State	
Time-of-Use (TOU)	Disconnectable	Interruptible DLC w/ A/C Switch
Critical Peak Pricing (CPP)	Configurable	Curtailable w/ Control DLC w/ PCT
Day-Ahead Real-Time Pricing (DA-RTP)	Manual	Curtailable w/o Control
Real-Time Real-Time Pricing (RT-RTP)	Behavioral	Peak-Time Rebate
Wholesale DR Programs	<i>Energy Bidding</i>	Home Energy Report
	<i>Capacity Bidding</i>	
	<i>Ancillary Services Bidding</i>	

Characterization of Current DR Opportunities

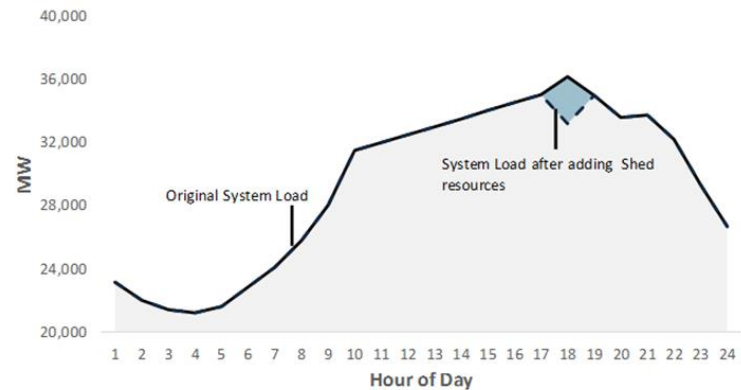
DR Opportunity (1)	Targeted Geographic Specificity (2)	Signal Variability (3)	Temporal Variability (4)	Availability (5)	Advanced Notice (6)	Automation (7)
TOU	○	⊙	⊙	○	○	○
CPP	○	⊙	⊙	○	○	○
DA-RTP	○	●	●	●	○	○
RT-RTP	○	●	●	●	⊙	○
Disconnectable	○	⊙	●	○	●	●
Configurable	○	⊙	●	○	●	⊙
Manual	○	⊙	⊙	○	⊙	○
Behavioral	○	○	○	○	○	○
Ratings Legend	○=System, ⊙=Secondary feeder ●=Primary feeder	○=Static ⊙=Pre-set ●=Dynamic	○=None ⊙=Set of hour ●=Any time	○=Limited ●=Unlimited	○=More than 4 hours ⊙= 6 min – 4 hours ●= 5 min. or less	○=Manual, ⊙=Automation with customer override ●=Automation without customer override

Rationale for Retail DR Programs

- ◆ Maintaining system reliability (e.g., system emergencies)
- ◆ Reducing the cost of procuring power during high price periods (e.g., responding to market conditions)
 - Distribution System Operators use DR to flatten out their load shape and minimize coincident transmission system peaks
- ◆ Addressing local reliability or congestion problems
- ◆ Non-wires alternatives- avoiding or deferring long term capital investments
- ◆ Meeting contractual obligations

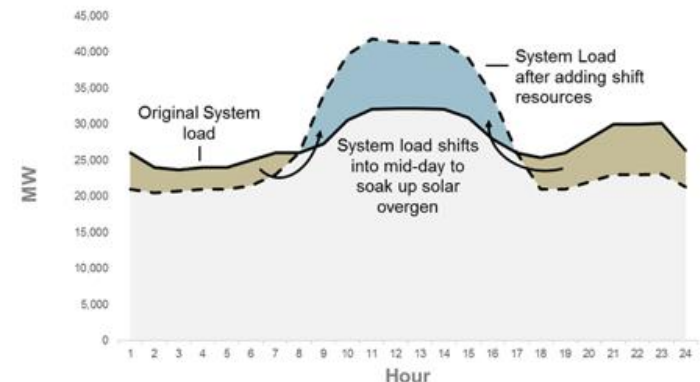
Demand Response 1.0

- ◆ **Historical DR** Programs included programs managed by utility with little or no measurement & verification of performance
- ◆ Incentive based programs were capacity services
- ◆ Retail rates designed to increase efficiency
 - ❑ One-way communication load-control devices installed on residential water heaters and air conditioners
 - ❑ Page or call large customers to invoke manual change in power consumption



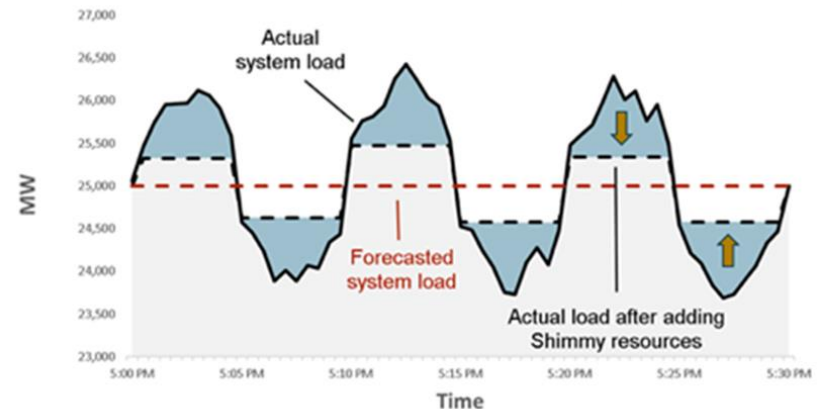
Demand Response 2.0

- ◆ Demand response is an integral part of most wholesale electricity markets and grid operation systems in US. Role of retail DR less important than DR 1.0.
 - ❑ Measurement and verification is more sophisticated & near real time measurements for confirmation of customer performance
- Role of DR services changed from providing capacity relief to increasingly flexible resources at the bulk power system
- Programs once managed by utilities are increasingly bid into wholesale markets



Demand Response 3.0 +

- ◆ Next generation of DR will likely address local system grid needs, in addition to bulk power systems
- ◆ Distributed Energy Resources will require localized, flexible retail DR programs that can manage volatility on distribution systems.
 - Non-wires alternative- defer capital investment in T&D infrastructure
 - Load following DR services for voltage support, regulating reserves
 - Automated controls that enable curtailment or interruption that optimize customer demand to meet grid needs



THANK YOU!

Jennifer Potter
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U.S. Wholesale Demand Response

David Kathan, Ph.D.
Federal Energy Regulatory Commission
Office of Energy Policy and Innovation

Views expressed do not necessarily represent the views of the Commission or any Commissioner



U.S. Wholesale Demand Response

- Starting in 1999, FERC has approved wholesale demand response proposals developed by Regional Transmission Operators (RTOs)
 - Capacity Market
 - Demand reductions compensated as capacity resources in exchange for obligation to perform when directed
 - Ancillary Services
 - If capable, adjustments to customer demand can be compensated as ancillary services (non-spinning, spinning, and regulation response)
 - Demand Bidding (or Economic Demand Response)
 - Demand reductions are bid and dispatched in energy markets like generation resources
 - Voluntary Emergency Demand Response
 - Compensation for demand reductions during system emergencies
- FERC rules allow demand response providers to aggregate customer demand reductions and bid this aggregated reduction into wholesale markets



Key FERC Rulemakings

- Order No. 719 (Wholesale Competition)
 - Changes to wholesale markets to permit demand response participation
 - Allows aggregated retail demand responses to bid into RTO and ISO markets, unless local laws or regulations do not permit a retail customer to participate
- Order No. 745 (Demand Response Compensation)
 - Requires that RTOs and ISOs pay demand response resources participating in the Day-Ahead and Real-Time Wholesale Energy Markets the Locational Marginal Price (or LMP) when
 - Demand response resources are capable of balancing supply and demand, and
 - Are cost-effective as determined by a net benefits test
- Orders Nos. 676-F and 676-G (M&V for Wholesale Demand Response and Energy Efficiency)



- **Demand Response as Capacity Resources**
 - Provides demand response during system emergencies
 - Participant receives capacity market-based payment for being available
 - Does not require instantaneous response, typically 30 minutes to 2 hours
 - Operated by electric utilities and demand response aggregators
 - Requires estimate of baseline customer demand
 - Requires extensive measurement & verification
 - RTO/ISO programs
 - PJM – Reliability Pricing Model
 - ISO-NE – Forward Capacity Market
 - NYISO – ICAP Special Case Resources
 - MISO – Load Modifying Resources



- **Demand Response as Ancillary Services**
 - Offers rapid-response resources to provide operating reserve and regulation services.
 - Operated by electric utilities and demand response aggregators
 - Aggregators typically bid resource into RTO markets on behalf of customer
 - Currently provided through direct load control and the control of large industrial loads (e.g., aluminum smelters)
 - RTOs that allow demand response to provide operating reserves:
 - CAISO, ISO-NE, MISO, NYISO, PJM
 - RTOs that allow demand response to provide regulation:
 - PJM, MISO



- **Demand Bidding in Energy Markets**

- Refers to the ability of customers to bid a price at which they will reduce demand
 - In most RTO markets, aggregators can bid customer demand resources into day-ahead energy markets, and are dispatched if economic
- Requires estimates of customer baseline usage
- Customers can rely upon a mix of remote control, autonomous control (such as smart thermostats) and manual actions to reduce load
- Most participants are large industrial facilities and commercial/educational establishments
- Focus of Order No. 745



- **Voluntary Emergency Demand Response**
 - Refers to voluntary customer load reductions during system emergencies. Customers may receive payments based on reductions achieved.
 - Reductions are not required, no penalties for non-performance
 - Aggregators (or the RTO/utility) typically notify customers of emergency conditions
 - Customers can rely upon a mix of remote control, autonomous control and manual actions to reduce load
 - NYISO's Emergency Demand Response Program is a good example



Demand Response Participation in Wholesale Markets

- Sources of demand response
 - Traditional utility demand response programs
 - Aggregators and curtailment service providers
 - Load Serving Entities
 - Direct end-use customer participation

RTO/ISO	2014		2015	
	Potential Peak Reduction (MW)	Percent of Peak Demand	Potential Peak Reduction (MW)	Percent of Peak Demand
California ISO (CAISO)	2,316	5.1%	2,160	4.4%
Electric Reliability Council of Texas (ERCOT)	2,100	3.2%	2,100	3.0%
ISO New England, Inc. (ISO-NE)	2,487	10.2%	2,696	11.0%
Midcontinent Independent System Operator (MISO)	10,356	9.0%	10,563	8.8 %
New York Independent System Operator (NYISO)	1,211	4.1%	1,325	4.3%
PJM Interconnection, LLC (PJM)	10,416	7.4%	12,910	9.0%
Southwest Power Pool, Inc. (SPP)	48	0.1%	0	0%
Total ISO/RTO	28,934	6.2%	31,754	6.6%



FERC v. EPSA Case

- On May 23, 2014, on appeal of Order No. 745, the D.C. Circuit in *EPSA* vacated Order No. 745 “in its entirety as *ultra vires* agency action.”
- The *EPSA* case was appealed to the U.S. Supreme Court, and oral arguments were held on October 14, 2015.
- The U.S. Supreme Court issued a decision in *FERC v. EPSA** in January 2016 that fully upheld FERC’s jurisdiction on wholesale demand response
- Supreme Court found that
 - FERC did possess adequate regulatory authority under the Federal Power Act; and
 - FERC’s decision to compensate demand response providers at locational marginal price was not arbitrary and capricious.

* *Elec. Power Supply Ass’n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev’d sub nom. FERC v. Elec. Power Supply Ass’n*, 136 S. Ct. 760 (2016)



Wholesale Demand Response M&V

- North American Energy Standards Board effort:
 - NAESB developed a standard M&V framework, which included key product definitions and categorizations
 - Products: Wholesale Electric Demand Response Energy, Capacity, Reserve and Regulation Products
 - Performance evaluation methodologies: (1) Maximum Base Load; (2) Meter Before / Meter After; (3) Baseline Type-I (Interval Meter); (4) Baseline Type-II (Non-Interval Meter); and (5) Metering Generator Output.
 - FERC adopted by reference Phase I wholesale DR M&V standards in April 2010 (Order 676-F) and Phase II wholesale DR and energy efficiency M&V standards in February 2013 (Order 676-G).
- A variety of M&V methods are in use at RTOs/ISOs, primarily based on calculating customer baselines
 - A good resource for these methods is the ISO/RTO Council North American Demand Response Characteristics Comparison matrix

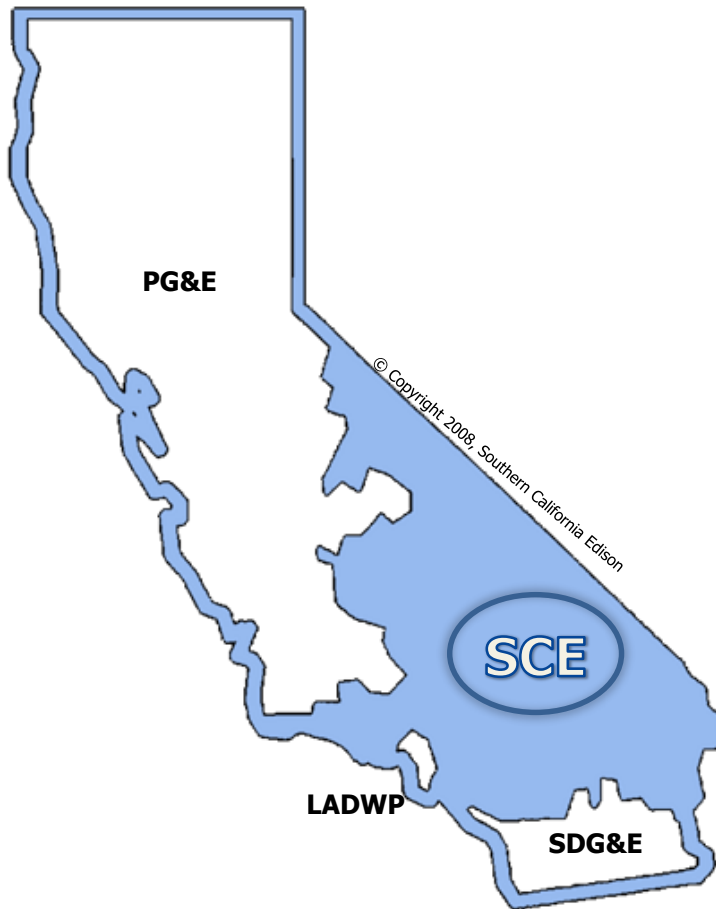
Demand Response Baselines: A Retail Perspective

Mark S. Martinez

Southern California Edison

April 13, 2017

Southern California Edison



SCE is one of the largest electric utilities in the United States

Service Area

- 50,000 square miles
- Over 400 cities and communities

Population Served

- 13 million residents
- 5 million customer accounts

2016 Business Highlights

- \$11.86 billion operating revenue
- \$51.3 billion in total assets
- 86 billion Kilowatt-hour delivered
- 23,091MW peak demand

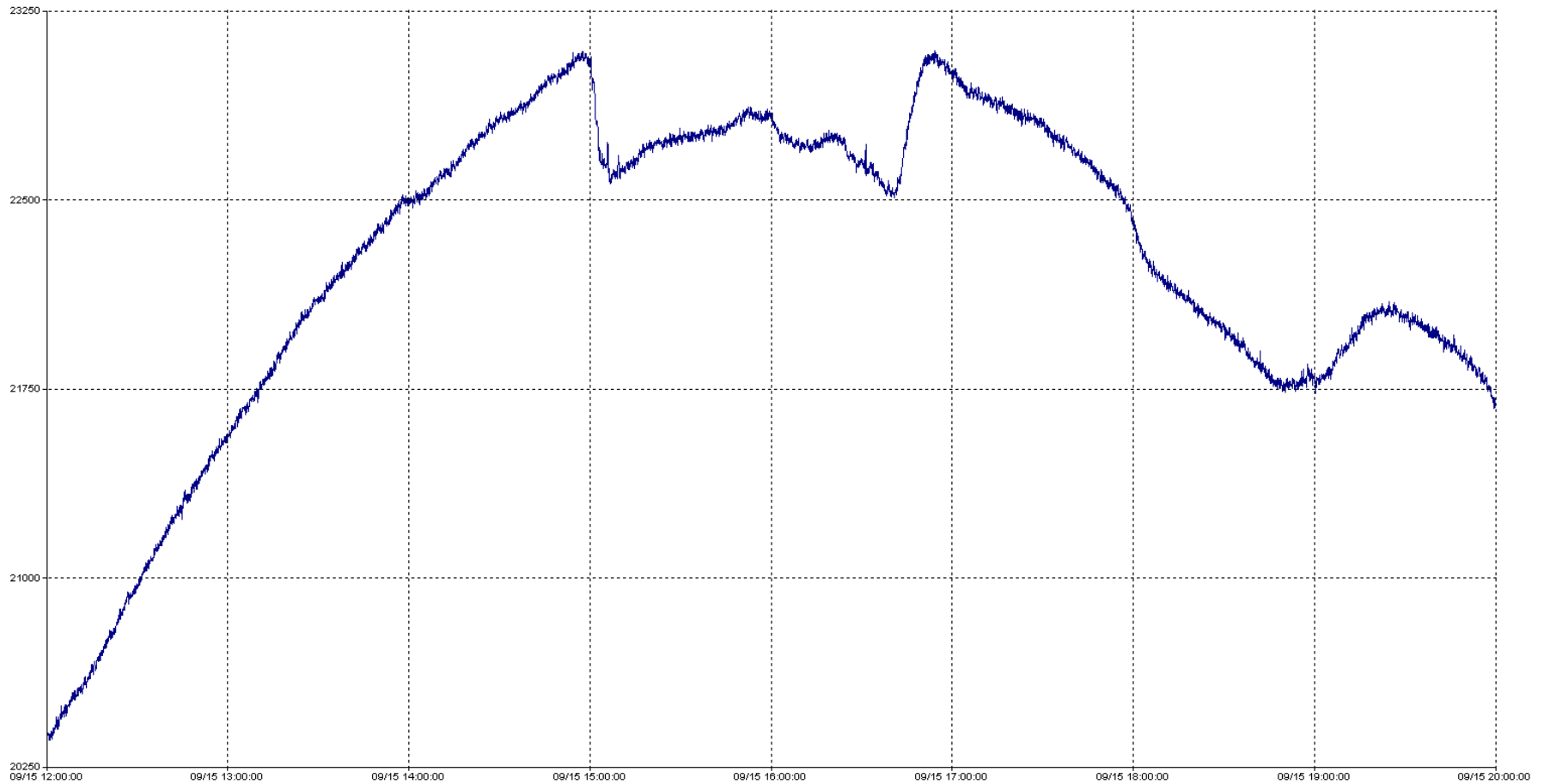
Industry leader in service excellence, renewable energy, demand side management, electric transportation, and smart grid infrastructure.

SCE DR Portfolio Overview

	Approx. Load Impact* (MW)	Program Design
Commercial & Industrial Customers		
Base Interruptible Program	698.3	Emergency interruptible load (customer control).
Agricultural Pumping & Interruptible	56.5	Emergency interruptible load (utility direct load control).
Demand Bidding Program	107.5	Economic, day-ahead energy.
Critical Peak Pricing	37.4	Economic, day-ahead energy (TOU rate structure).
Aggregator Managed	118.1	Third-party economic energy and capacity.
Summer Discount Plan	54.3	A/C cycling direct load control (both economic and emergency).
Residential Customers		
Summer Discount Plan	234.0	A/C cycling direct load control (both economic and emergency).
Peak Time Rebate	26.6	Economic, day-ahead energy.

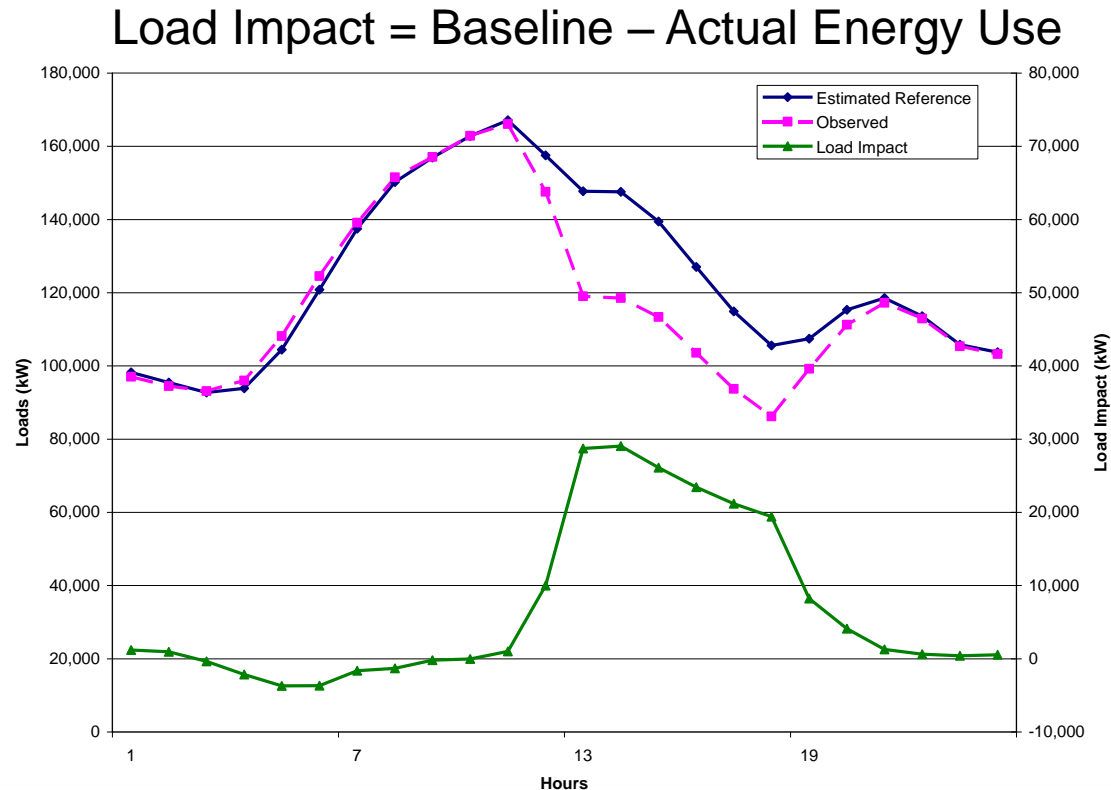
*Approximate MW using 2015 Ex Ante Load Impact Tables for 2016 August monthly peak

Residential A/C cycling event on 9/15/14



EM&V – how low did we go?

- In most instances, load impacts from DR events are estimated by comparing the reference level energy use (baseline) in each hour with actual energy use in the hour on each event day.



Baselines – what did *not* happen

A baseline calculation is a “counter-factual”, or pure theoretical, mathematical estimate of what a customer would have done during a DR event.

So the question is, what is the best baseline?

Baseline calculations that are accurate and unbiased are among the most challenging aspects of DR programs, as they can only estimate the counterfactual.

Well designed baseline

- Results in accurate load impact estimates.
- Properly compensates customers for load reductions.

Poorly designed baseline

- Can deprive customers of just and reasonable compensation, resulting in dissatisfaction and loss of participation.
- Can reduce the benefits of DR resources and devalue the overall cost effectiveness of programs.

Baselines matter in many ways

As DR plays an increasing role in organized markets and system planning, the right baseline “matters” for local grid operations, financial settlements for customers, and for ISO/RTO resource planning.

Grid Operations



Magnitude of demand savings that a DR resource will deliver to the electric grid.

Financial Settlement



Magnitude of curtailment by customer, as estimated by the baseline, determines financial settlement.

ISO/RTO Planning

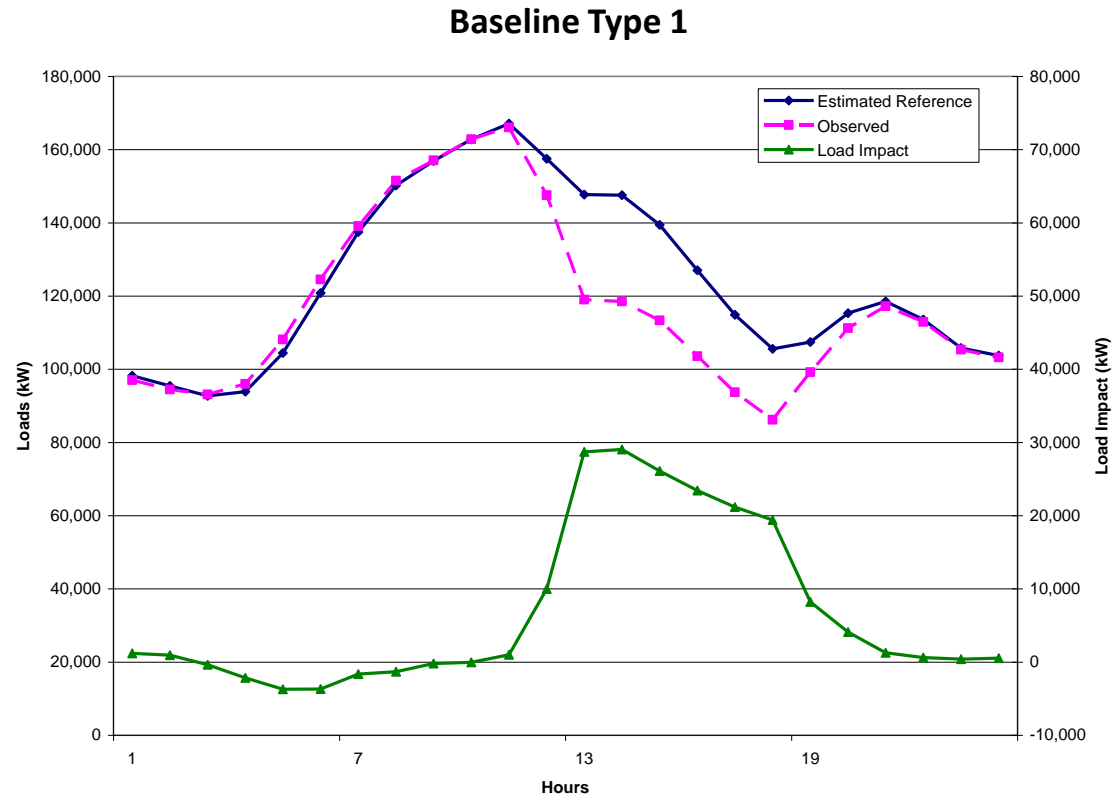


Amount of DR expected from enrolled resources. Includes comparison with alternate grid resources.

Baseline Type 1

Baseline type 1 is the most commonly used baseline method for performance settlements of participants in retail DR programs.

- Type 1 baseline is based on historical interval meter data for each demand resource.
- It may also include other variables such as weather and calendar data on the day of the event.
- Statistical sampling of sites is not permitted.
- Day-of DR event adjustment may be allowed to minimize baseline error.



"X of Y" Baselines

The most commonly DR baseline is the "X of Y" approach, which is transparent and easily developed for expediting customer settlements.

- *X of Y baselines are a performance evaluation methodology using the pre-event historical interval meter data from a demand resource. The approach uses data for the "Y" most recent "non-DR" days preceding a DR event. The baseline for the DR event period is then calculated from the hours averaged from a select number of "X" days within the "Y" days.*

Y Value

The specified Y value of days are specified as being prior to a DR event, often between 5 and 10 but as much as 20. These days should not include any DR events, and should be representative of the event day (season, weekday).

X Value

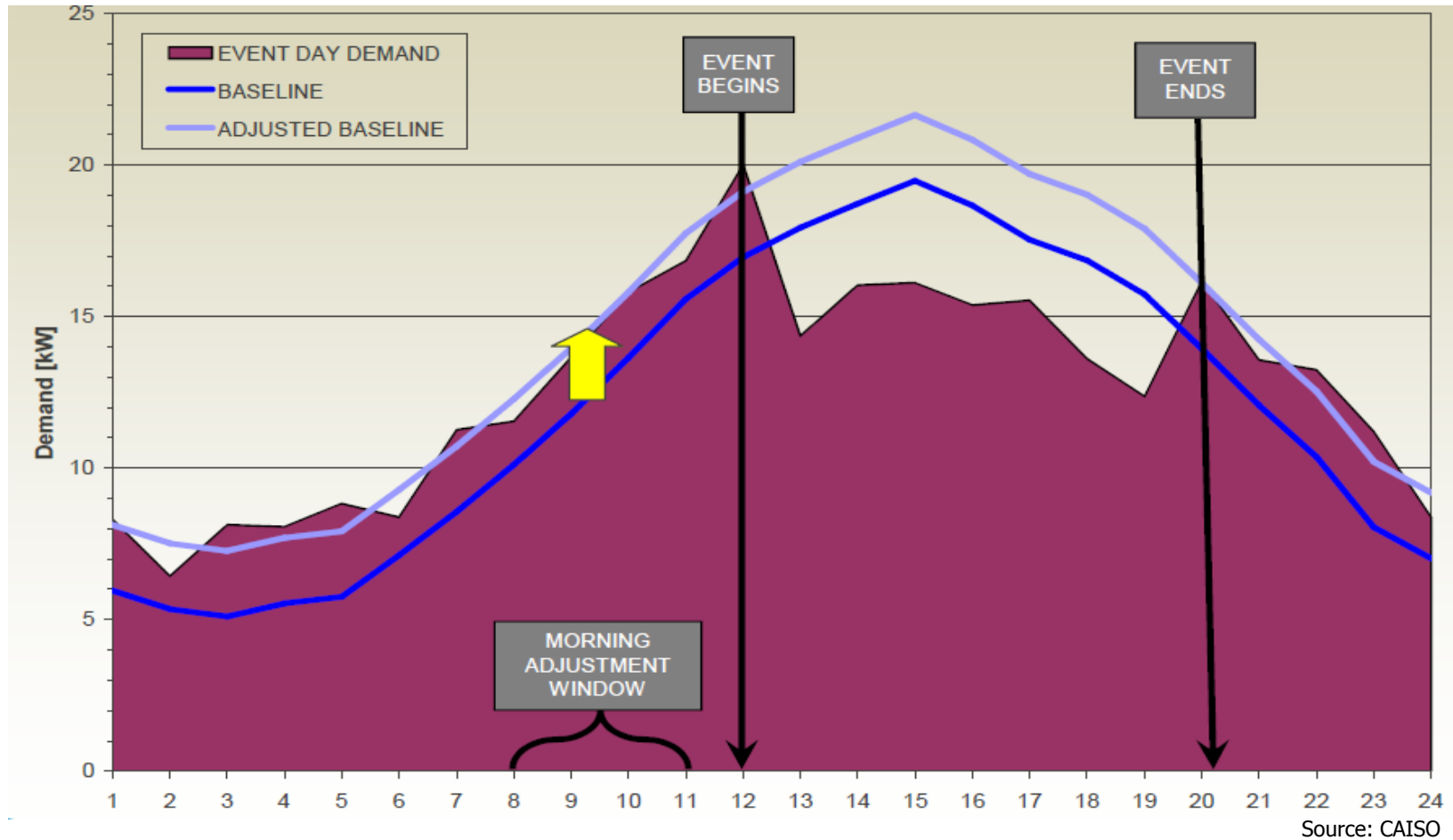
The X group of days is a subset of the Y days that contain intervals that better represent the DR event day. For example, a "high 5 of 10" baseline would collect meter data from the previous 10 non-event days (excluding weekends, etc.) and select the 5 "best" days with the hours of the highest load during the event hours.

SCE – 10 of 10 baseline approach

This is used for providing customer capacity and energy payments

	Noon - 1 p.m.	1 p.m. - 2 p.m.	2 p.m. - 3 p.m.	3 p.m. - 4 p.m.	4 p.m. - 5 p.m.	5 p.m. - 6 p.m.	6 p.m. - 7 p.m.	7 p.m. - 8 p.m.
7/29/09	5808	5808	5760	5856	5808	5808	5808	5760
7/30/09	7344	7440	7440	7392	7488	7392	5616	5616
7/31/09	7488	4944	6000	7008	7344	7440	5472	5712
8/3/09	4992	5184	5088	5232	5184	5232	5232	5376
8/4/09	5184	5184	5136	5088	5088	5136	5184	5232
8/5/09	5232	5280	5088	4896	4992	5136	4992	4848
8/6/09	5040	5184	5136	5232	5184	5184	5232	5136
8/7/09	4848	4896	4752	5136	5136	4992	5040	5040
8/10/09	5088	5088	5040	5184	5088	5088	5040	5088
8/11/09	4944	4848	5040	5040	5088	5040	4944	4992
10-Day Average Baseline	5597	5386	5448	5606	5640	5645	5256	5280
Multiply by "Day-Of" Adjustment Ratio	1.0728							
10-Day Average Baseline with "Day-Of" Adjustment	6004	5778	5845	6015	6051	6056	5639	5665

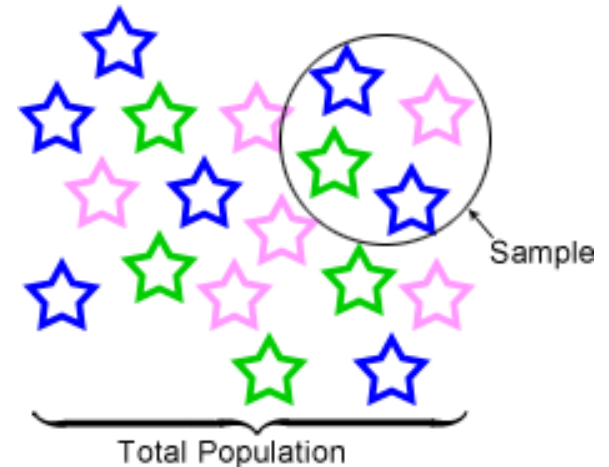
Day of Adjustment



Baseline Type 2

Baseline type 2 is a performance evaluation methodology that uses statistical sampling to estimate electricity consumption of an aggregated demand resource.

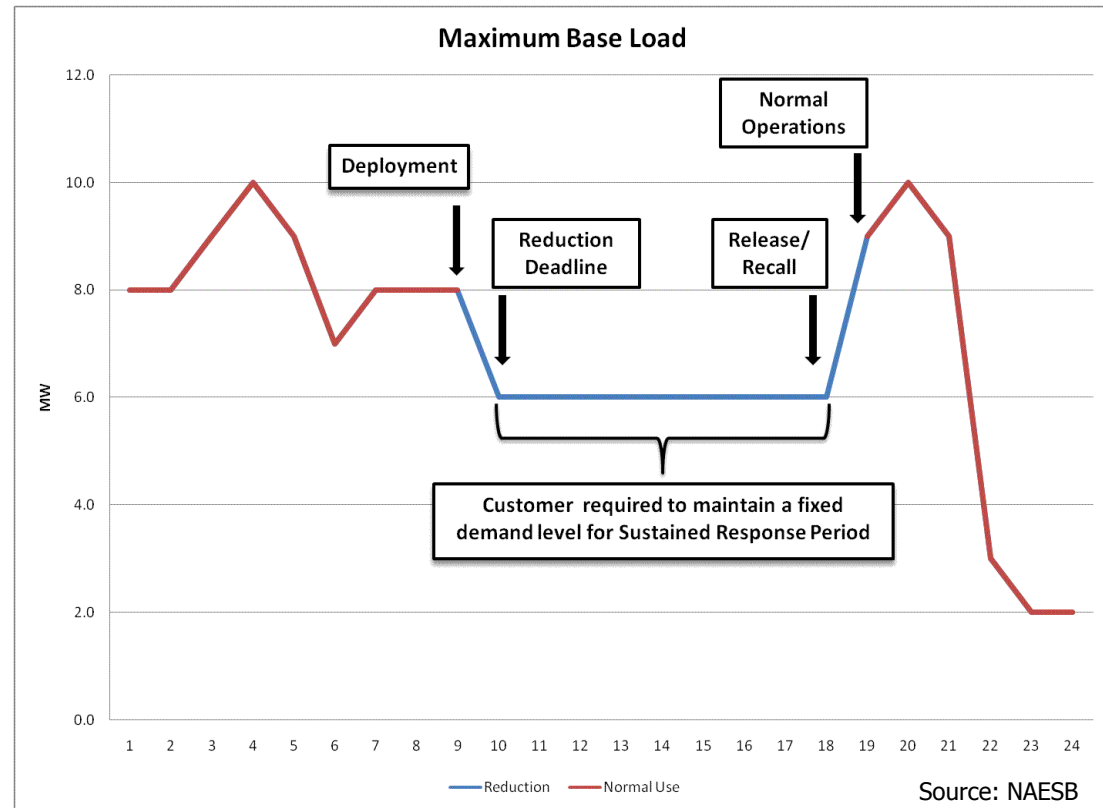
- Type 2 is used in cases where interval meter data is not available for individual sites. The need for type 2 baselines will diminish as interval meters become more commonplace.
- Statistical sampling techniques are used to generate a baseline for a portfolio of customers.
- This can be used when a group of sites (especially residential) are homogenous with similar load behavior. A few sites can be metered in order to develop an average load estimate per site, and then use this to allocate load from the aggregated baseline.



Maximum Base Load (non-baseline)

Maximum base load is a performance evaluation methodology based solely on the ability of a demand resource to reduce to a specified level of electricity demand.

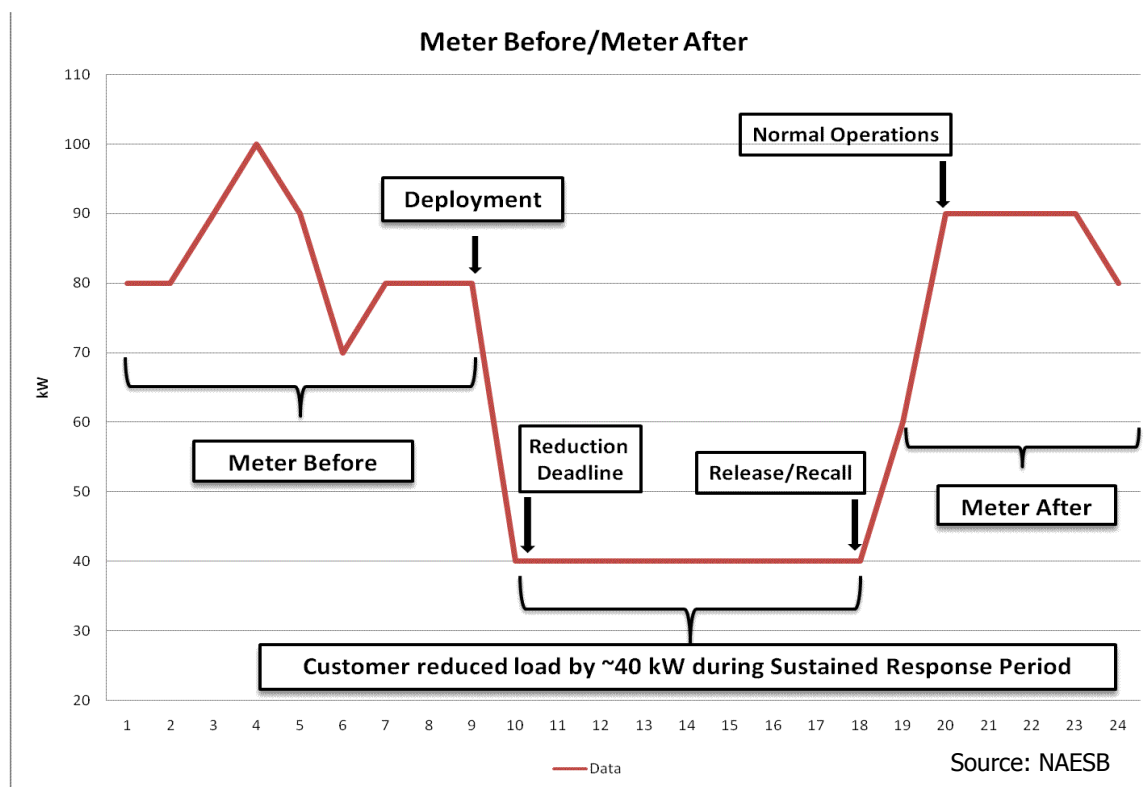
- MBL is sometimes referred to as the *Drop To* method. It is superior for highly variable loads that do not are not appropriate for baseline style programs.
- This method should use coincident peak hours to capture approximate load reductions during DR events.
- This is not a baseline estimation method.



Before Meter/After Meter (non-baseline)

Meter Before/Meter After is a performance evaluation methodology in which electricity demand over a prescribed period of time prior to DR deployment is compared to similar readings during a sustained response period.

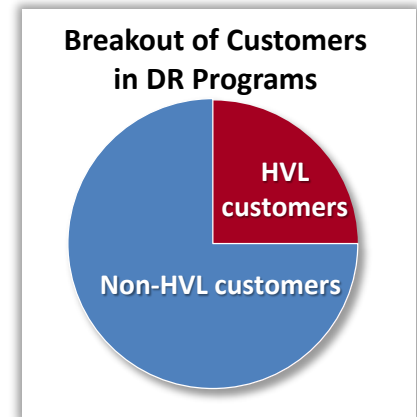
- The load shape for this performance metric is static.
- Meter data from individual sites is utilized.
- It relies on a small interval of historical meter data.
- This **is not** a baseline estimation methodology.



Highly Variable Loads (HVL)

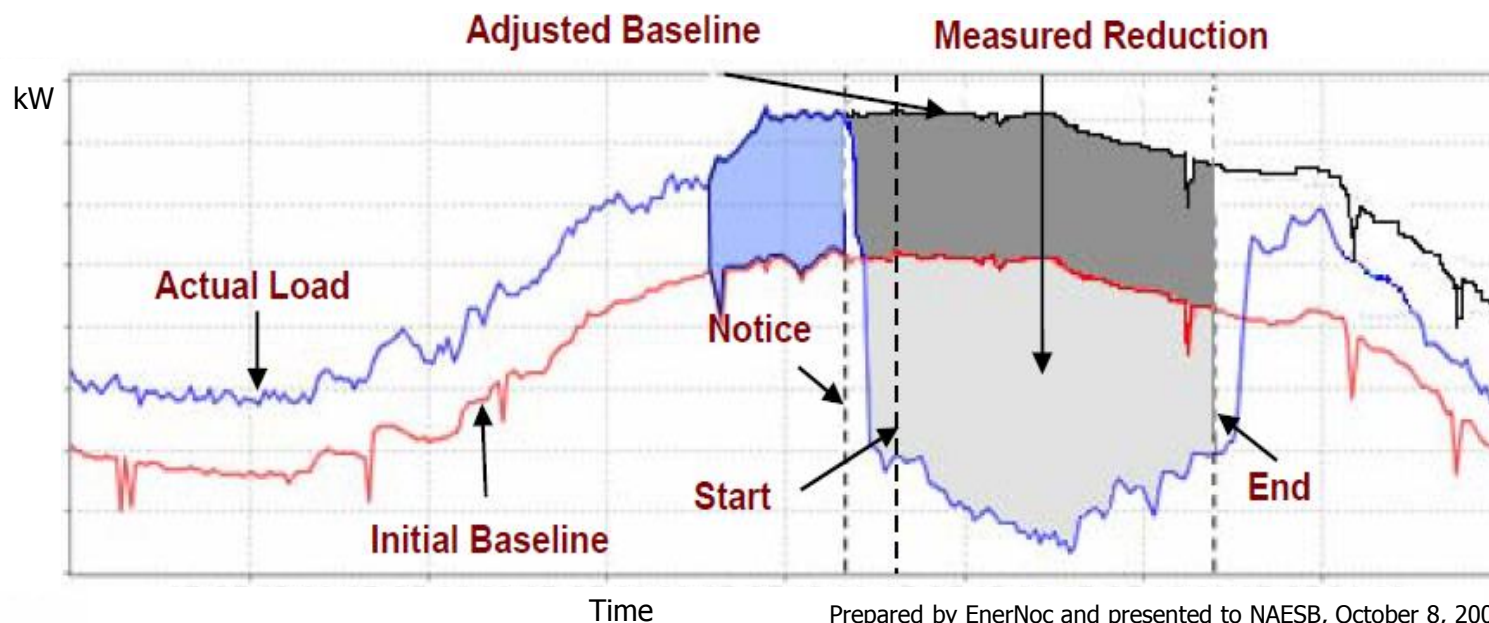
DR resources that have highly variable load patterns pose a problem for baseline analysis because historic meter data can be an unreliable indicator of event day usage.

- Baseline errors from HVL customers are problematic because they carry over into load impact estimates of performance and create settlement errors.
- In a study for the California PUC, HVL customers were defined as those whose average variability around their mean use in the event window is 30% or more. One quarter of DR customers were found to fit this definition, with substantial variation by program and industry type.
- Customers with irregular baselines are most common in agriculture, construction, other utilities, schools and sometimes manufacturing. A preferred DR performance methodology for these customers would be the Guaranteed Load Drop. **HVL customers should not participate in DR programs that use baselines for compensation.**



Teasing Settlements from DR Events

The elements of baselines are brought together in this illustration of a DR event day. In this case the adjusted baseline captures circumstances on the day of the event and better reflects the actual resource provided than the unadjusted baseline would have captured.



Prepared by EnerNoc and presented to NAESB, October 8, 2009

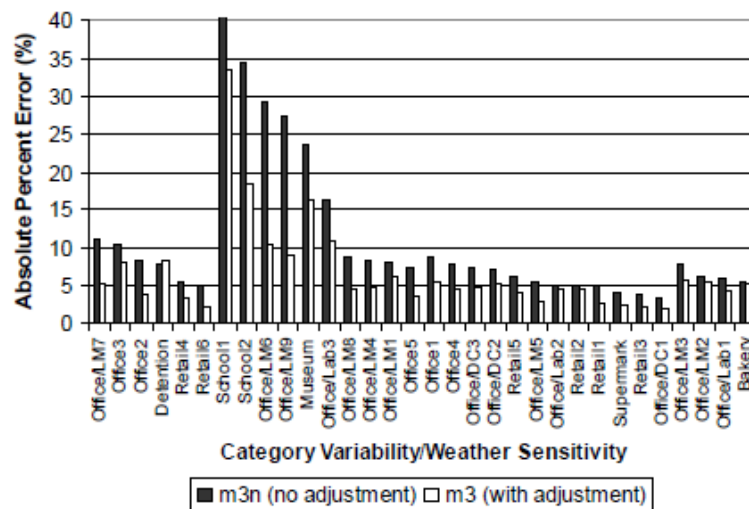
The illustrates both the challenges and complexities for finding the “counterfactual”.

Final Comments

Baseline measurement accuracy is constantly under assessment with changes and adjustments to **provide appropriate settlements** for DR program participants.

- ◆ Numerous studies have concluded that **applying a morning adjustment factor** significantly reduces bias and improves accuracy of baseline load profiles.
- ◆ Such adjustments use actual load data in the hours prior to the event to adjust the X of Y baseline. Adjustments may be capped or uncapped. **Capped adjustments limit the magnitude of a baseline adjustment.**
- ◆ Customers with highly variable loads typically have the most irregular load profiles and require the largest adjustments. **The better option is for such customers to transition to a non-baseline style program.**

The right customer for the program baseline.



Thank you!

Mark S. Martinez

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www.sce.com/drp

Evaluation, Measurement and Verification (EM&V) of Demand Response load reductions in wholesale markets

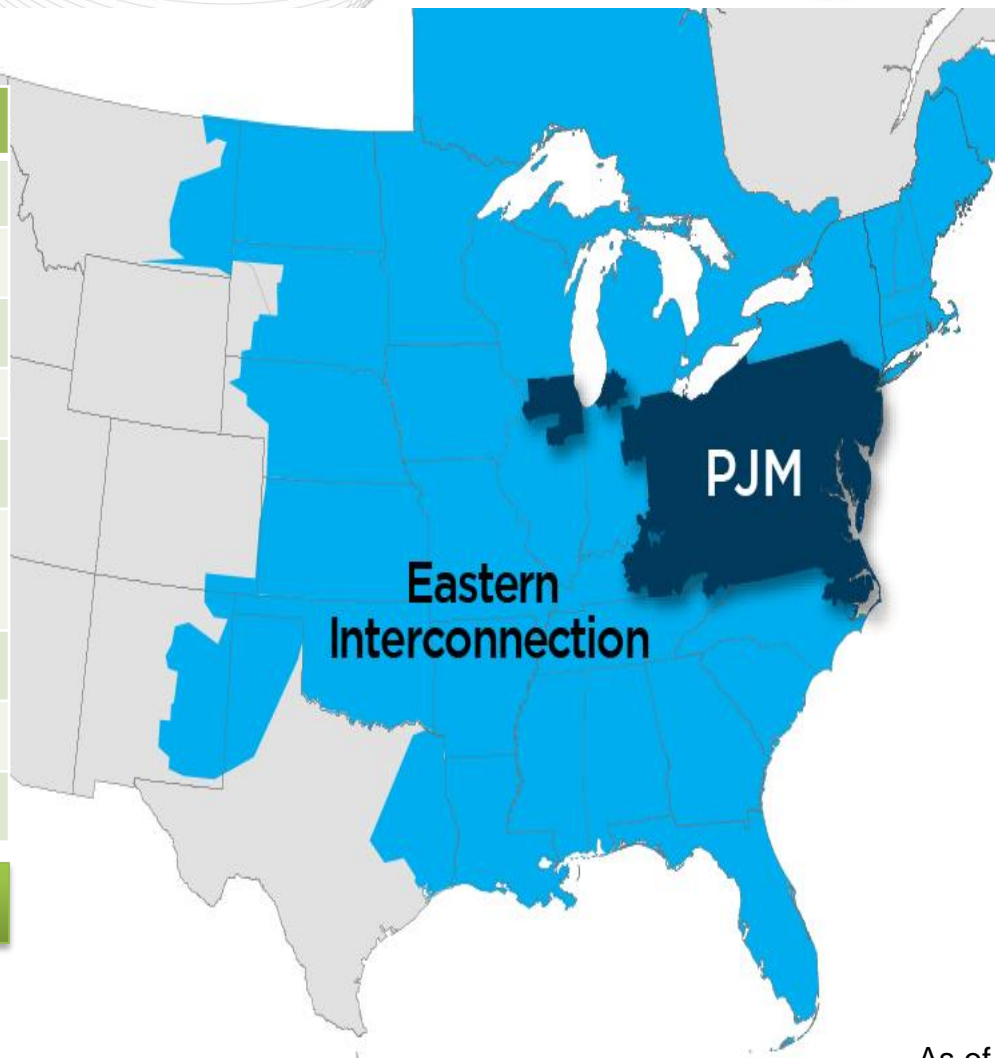
Pete Langbein



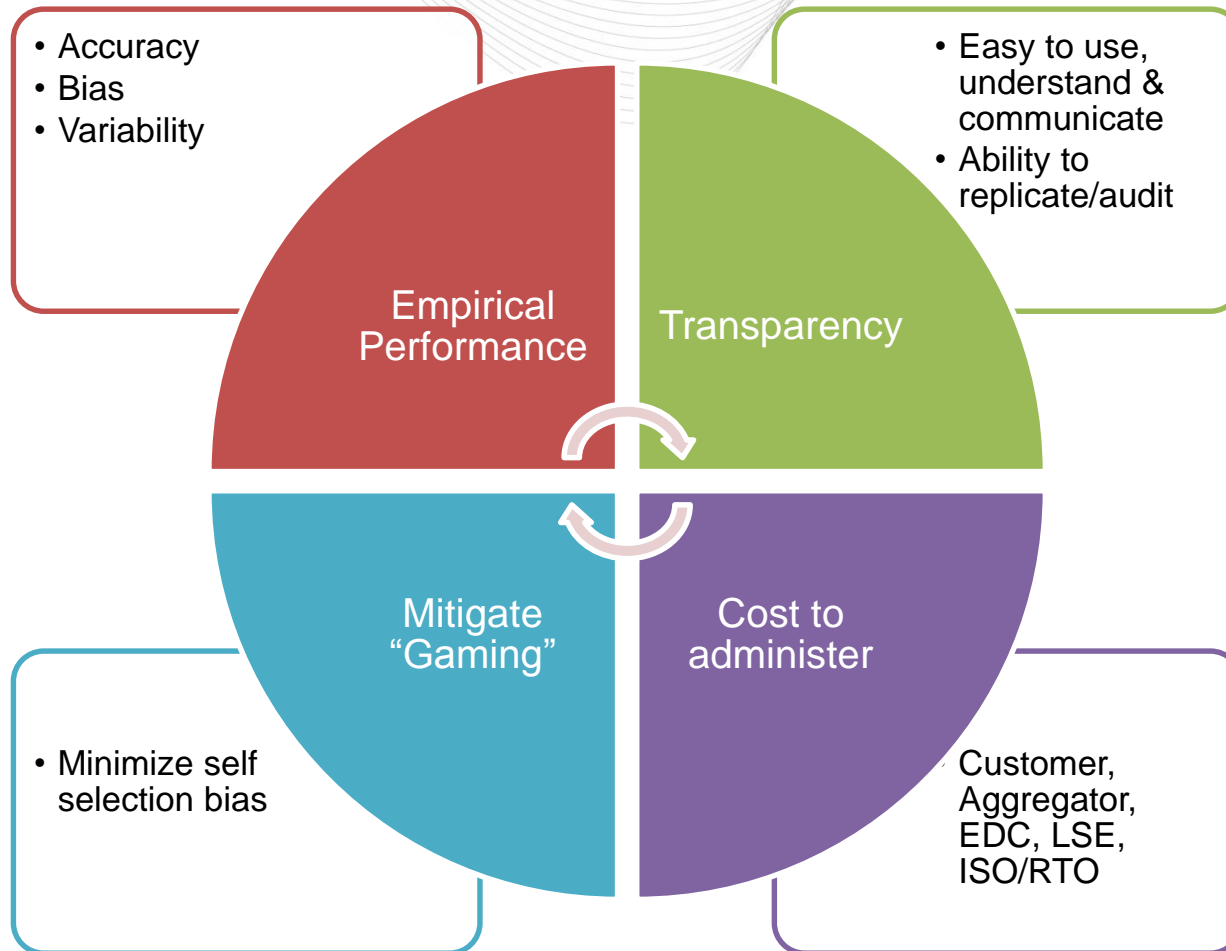
Key Statistics

Member companies	990+
Millions of people served	65
Peak load in megawatts	165,492
MW of generating capacity	176,569
Miles of transmission lines	82,546
2016 GWh of annual energy	792,314
Generation sources	1,304
Square miles of territory	243,417
States served	13 + DC

21% of U.S. GDP produced in PJM



As of 2/2017

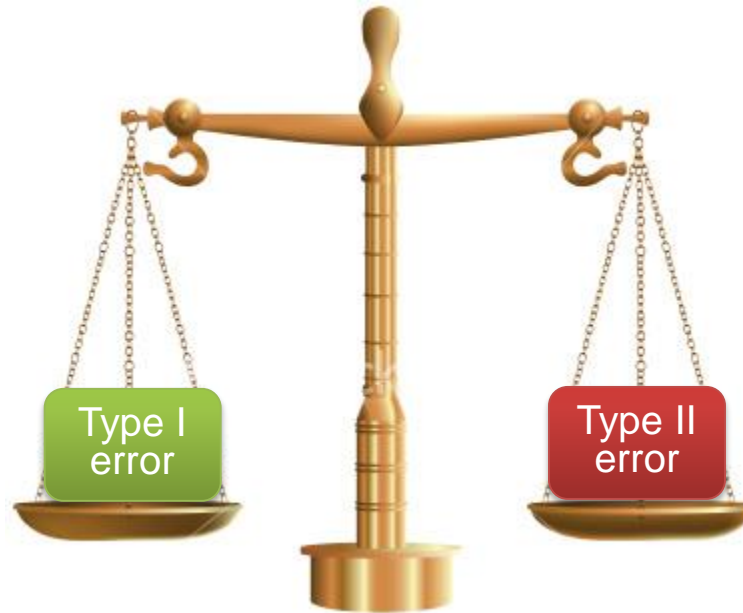


Measurement is done to determine revenue and/or penalties

- Energy
- Capacity
- Ancillary Services
 - Day Ahead Scheduling Reserves
 - Synchronized Reserves (10 minute spin)
 - Regulation (frequency control)

EM&V approach can be different by market

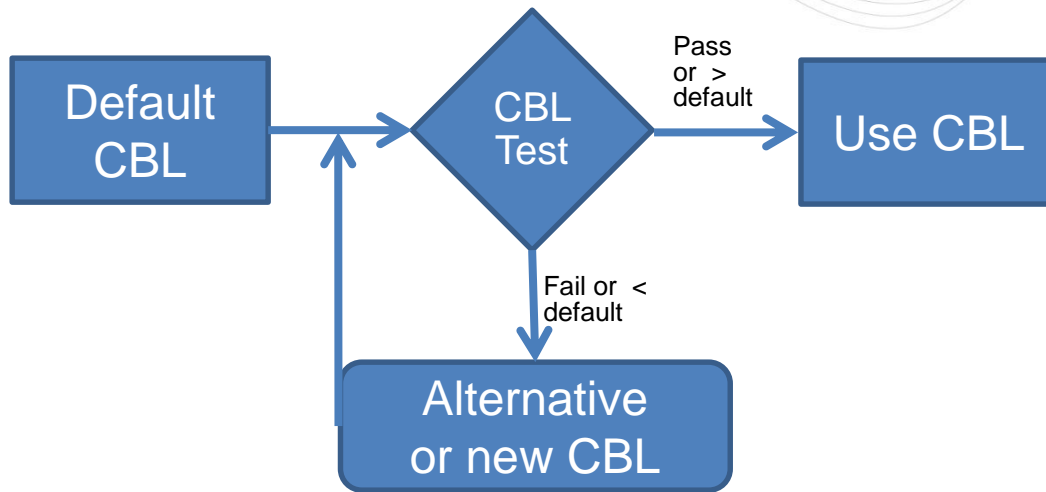
Customer Baseline Load (“CBL”) = customer load forecast



false positive – estimate a load reduction but customer did not reduce load

false negative – estimate no load reduction but customer did reduce load

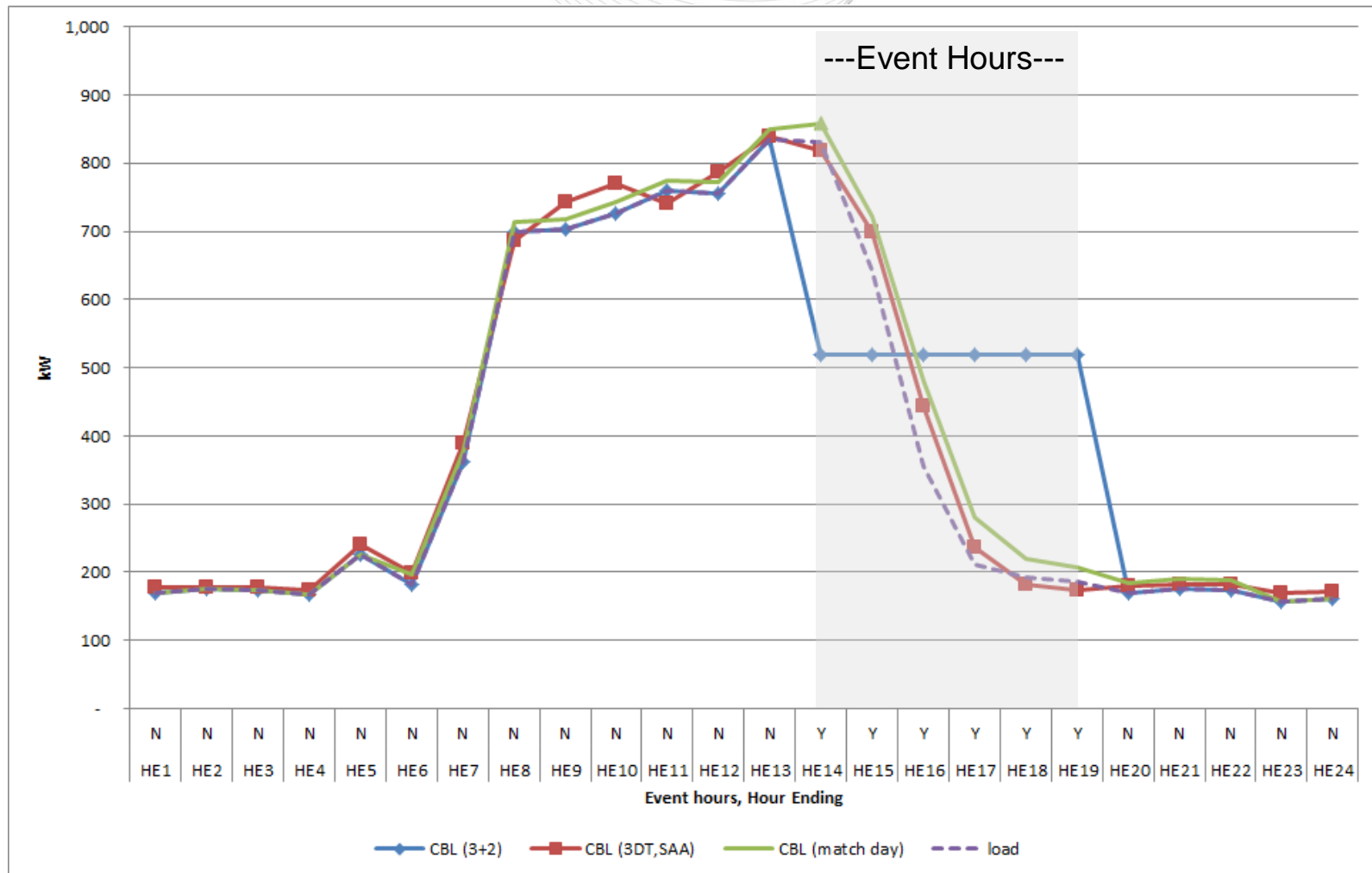
There will always be errors (Forecast/CBL vs Actual load) – maximize accuracy and minimize bias and variability



CBL Test = Relative Root Mean Square Error (RRMSE) for prior 30 days during typical participation hours < defined value

- Must be able to reasonably predict load in order to reasonably determine load reductions
- Consistent approach in market
- Flexibility to implement/develop better CBLs
- Objective approach to evaluate/compare CBLs

NAME	DESCRIPTION
Same Day (3+2)	Take average of 3 hours before and 2 hours after (skip hour before/after)
Match Day (3 day average)	Compare usage on event during before/after event to historic usage and pick days to minimize RRMSE
3 Day Types	Standard (WD high 4 of 5, Sat, Sun/Hol high 2 of 3)
5 Day Types	Mon, Fri high 3 of 4; Tues/Wed/Thurs high 4 of 5; Sat, Sun/Hol high 2 of 3, 60 day lookback
Manual	Manual CBL (not generated by system)
7 Day Types	Mon, Tues, Wed, Thurs, Fri, Sat, Sun/Hol average of 3; 60 day lookback
Metered Generation	Metered Generation
3 Day Types with SAA (DEFAULT)	Standard (WD high 4 of 5, Sat, Sun/Hol high 2 of 3) with Symmetric Additive Adjustment
3 Day Types with WSA	Standard (WD high 4 of 5, Sat, Sun/Hol high 2 of 3) with Weather Sensitivity Adjustment
5 Day Types with SAA	Mon, Fri high 3 of 4; Tues/Wed/Thurs high 4 of 5; Sat, Sun/Hol high 2 of 3, 60 day lookback, with Symmetric Additive Adjustment
5 Day Types with WSA	Mon, Fri high 3 of 4; Tues/Wed/Thurs high 4 of 5; Sat, Sun/Hol high 2 of 3, 60 day lookback, with Weather Sensitivity Adjustment
7 Day Types with SAA	Mon, Tues, Wed, Thurs, Fri, Sat, Sun/Hol average of 3; 60 day lookback, with Symmetric Additive Adjustment
7 Day Types with WSA	Mon, Tues, Wed, Thurs, Fri, Sat, Sun/Hol average of 3; 60 day lookback, with Weather Sensitivity Adjustment
MBL(Max Base Load)	Average daily minimum load during event period for 5 most recent nonevent days



- CBL primarily calculated at premise level
 - “utility account number”
- Small premises may be aggregated together to enable market participation (>100kw)
 - CBL calculated from aggregate load data.
- Capacity market performance aggregated across dispatched premises based on geographic location

- Capacity market – EM&V based on avoided demand
 - load must be below peak levels when dispatched.
- 5 minute energy settlements - typically shorter time period = higher variation = greater error.
- Sophisticated approach does not mean more accurate (regression approach only marginally more accurate for specific circumstances to date)
- Ancillary Services – load before/after typically used for CBL

As data availability goes up, we may be able to improve accuracy

- Kema/PJM CBL empirical analysis
 - <http://www.pjm.com/~media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx>
- PJM training material
 - CBL example, Slide (36-42)
 - <http://www.pjm.com/~media/training/core-curriculum/ip-dsr/economic-demand-side-response-training.ashx>
- PJM Manual 11, section 10.4.2, CBL inventory and calculations
 - <http://www.pjm.com/~media/documents/manuals/m11.ashx>
- Peter Langbein, peter.langbein@pjm.com

- RRMSE example

Relative Root Mean Squared Error (RRMSE)

1. To perform the RRMSE calculation, daily CBL calculations are first performed for each CBL method using hours ending 14 through hours ending 19 as the simulated event hours for each of the 30 non-event days according to each CBL method rules.
2. Actual Hourly errors are calculated by subtracting the CBL hourly load from the actual hourly load for each of the simulated event hours of the non-event day.
3. The Mean Squared Error (MSE) is calculated by summing the squared actual hourly errors and dividing by the number of simulated event hours.
4. The Average Actual Hourly Load is the average of the actual hourly load for each of the simulated event hours.
5. The Relative Root Mean Squared Error (RRMSE) is calculated by taking the square root of the quantity $(\text{MSE} / \text{Average Actual Load})$.

RRMSE Example

Example of RRMSE calculated over 10 day period

1. Daily CBL calculations are first performed for each CBL method using hours ending 14 through hours ending 19 as the simulated event hours for each of the 30 non-event days according to each CBL method rules.

		Baseline Hourly Loads (kW)						Actual Hourly Loads (kW)					
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
customer	Date	1-2PM	2-3PM	3-4PM	4-5PM	5-6PM	6-7PM	1-2PM	2-3PM	3-4PM	4-5PM	5-6PM	6-7PM
R2001	18-Aug-11	508	520	517	506	488	461	492	494	500	502	502	481
R2001	19-Aug-11	83	82	72	53	47	35	64	59	38	47	5	5
R2001	20-Aug-11	349	342	287	267	237	196	326	322	313	301	294	222
R2001	21-Aug-11	3,482	3,468	3,843	3,606	3,556	3,445	3,771	3,761	3,730	4,023	3,487	3,361
R2001	22-Aug-11	439	445	446	416	425	404	383	382	383	381	387	391
R2001	23-Aug-11	386	397	394	370	229	194	353	386	375	312	235	178
R2001	24-Aug-11	92	92	92	93	92	92	82	85	83	85	84	86
R2001	25-Aug-11	3,204	3,229	3,257	3,208	3,185	3,115	2,964	2,964	2,961	2,386	2,833	2,770
R2001	26-Aug-11	660	625	568	532	493	482	613	583	566	551	535	499
R2001	27-Aug-11	6,397	6,377	6,322	6,308	6,411	6,343	7,165	7,098	7,047	6,918	6,799	6,820

Example of RRMSE calculated over 10 day period

- Actual Hourly errors are calculated by subtracting the actual hourly load from the CBL hourly load for each of the simulated event hours of the non-event day.
- The Mean Squared Error (MSE) is calculated by summing the squared actual hourly errors and dividing by the number of simulated event hours.
- The Average Actual Hourly Load is the average of the actual hourly load for each of the simulated event hours.
- The Relative Root Mean Squared Error (RRMSE) is calculated by taking the square root of the MSE/Average Actual Load.

customer	Date	Actual Hourly Error (kW)						MSE	Average Actual kW	Relative RMSE
		(u)	(v)	(w)	(x)	(y)	(z)			
		1-2PM	2-3PM	3-4PM	4-5PM	5-6PM	6-7PM			
R2001	18-Aug-11	16	26	17	4	(14)	(20)	65,443	1,564	16%
R2001	19-Aug-11	19	23	34	6	42	30			
R2001	20-Aug-11	23	20	(26)	(34)	(57)	(26)			
R2001	21-Aug-11	(289)	(293)	113	(417)	69	84			
R2001	22-Aug-11	56	63	63	35	38	13			
R2001	23-Aug-11	33	11	19	58	(6)	16			
R2001	24-Aug-11	10	7	9	8	8	6			
R2001	25-Aug-11	240	265	296	822	352	345			
R2001	26-Aug-11	47	42	2	(19)	(42)	(17)			
R2001	27-Aug-11	(768)	(721)	(725)	(610)	(388)	(477)			
								$\Sigma e^2/n$	= average(g:l)	=SQRT(s)/(n)

Discussion/Questions

For more EM&V information see:

- Webinars: <https://emp.lbl.gov/emv-webinar-series>
- For technical assistance to state regulatory commissions, state energy offices, tribes and regional entities, and other public entities see: <https://emp.lbl.gov/projects/technical-assistance-states>
- Energy efficiency publications and presentations – financing, performance contracting, documenting performance, etc. see: <https://emp.lbl.gov/research-areas/energy-efficiency>
- New Technical Brief - *Coordinating Demand-Side Efficiency Evaluation, Measurement and Verification Among Western States: Options for Documenting Energy and Non- Energy Impacts for the Power Sector*
<https://emp.lbl.gov/publications/coordinating-demand-side-efficiency>

From Albert Einstein:

“Everything should be as simple as it is, but not simpler”

“Everything that can be counted does not necessarily count; everything that counts cannot necessarily be counted”